STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA	**)**	
GAS & ELECTRIC COMPANY	**)**	
d/b/a VECTREN ENERGY DELIVERY	**)**	**CAUSE NO. 43839**
OF INDIANA, INC.	**)**	
(VECTREN SOUTH – ELECTRIC)	**)**	

DIRECT TESTIMONY OF

TYLER E. BOLINGER – PUBLIC'S EXHIBIT NO. 1

ON BEHALF OF

THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

JUNE 25, 2010

TESTIMONY OF TYLER E. BOLINGER
CAUSE NO. 43839
<u>VECTREN SOUTH - ELECTRIC</u>

I. Purpose and Qualifications

Q: Please state your name and business address.

A: My name is Tyler E. Bolinger, and my business address is 115 W. Washington St., Suite 1500 South, Indianapolis, IN 46204.

Q: By whom are you employed and in what capacity?

A: I am employed as the Director of the Electric Division for the Indiana Office of Utility Consumer Counselor (OUCC).

Q: Please describe your credentials.

A: I graduated from Ohio University in 1982 with a Bachelor's degree in economics. I was named to the *Phi Beta Kappa* Honor Society and the National Dean's List during my senior year of undergraduate studies. I attended graduate school at Michigan State University and received a Master's degree in economics in 1984. In 1985, I completed all course work and comprehensive examinations required for a Ph.D. degree in economics. I have also completed several courses in accounting, including intermediate accounting and advanced financial accounting.

I became Director of the OUCC's Electric Division in May, 2008. Prior to that, I was the OUCC's Natural Gas Director (1999 to 2008) and the OUCC's Chief Economist (1994 to 1999) with responsibilities in electricity, natural gas, telecommunications, water, and sewer regulation. I began my regulatory career with the Indiana Commission as a Utility Analyst in 1987. In 1990 I was transferred to the OUCC at the time of the reorganization of the Commission and the OUCC. During 1985 and 1986, I worked as an Economic Analyst with the Indiana Department of Commerce.

While employed by the IURC, I attended the regulatory studies program at Michigan State University sponsored by the National Association of Regulatory Utility Commissioners (NARUC). Since then I have attended numerous other energy, regulatory, and financial training seminars. I have worked on a wide variety of gas, electric, telecommunications, water and sewer issues, including Alternative Regulatory Plans (ARPs). I have testified before the IURC on many issues, including ARPs, regulatory policy, utility planning, cost of capital, fair return, fair value ratemaking, utility finance, gas costs, gas procurement, and gas rate decoupling.

Q: What is the purpose of your testimony?

A: I will begin by providing an overview of major concerns related to Vectren South's proposed electric rate increase. I will then overview and introduce the OUCC's case in chief and expert witnesses. Finally, I will explain the OUCC's policy concerns with Petitioner's proposals to: (1) impose a step two rate increase to occur in 2013 related to dense pack investments; (2) change the fuel adjustment clause (FAC) by weather normalizing actual earnings for purposes of the FAC earnings test; and (3) exclude the cost of fuel from base rates, resulting in base rates that omit a major component of Petitioner's cost of service.

Q: What did you do to prepare to testify in this Cause?

A: I reviewed the petition and exhibits filed by Petitioner (Vectren South – Electric or simply Vectren South.) I reviewed the pre-hearing conference order. I attended public hearings on Petitioner's case-in-chief, including the hearing in Indianapolis and the field hearing in Evansville. I conducted relevant discovery and reviewed the results. I attended numerous meetings with OUCC Staff, attorneys, and consultants to discuss the issues in this Cause. All work related to this testimony was done by me or under my supervision.

II. Introduction and Overview

Q: Would you please identify some of the major concerns related to Vectren South's proposed base electric rate increase?

A: Generally, my areas of concern include:

1. Petitioner's existing high electric rates;
2. Petitioner's high costs of power production;
3. Petitioner's pronounced reliance on rate adjustment mechanisms (i.e. trackers); and
4. Petitioner's highly recessionary test year.

Q: Please briefly describe the concern about Petitioner's existing high rates?

A: For residential customers at least, Vectren South already has the highest electric rates in Indiana. My Attachment TEB-1 contains a copy of the 2009 Residential Bill Survey from the Commission web site. Table 2 of the Bill Survey shows that Vectren South's residential charges, for a customer using 1000 kWh, already exceed the charges of all jurisdictional REMCs, Municipals, and Investor Owned Utilities (IOUs) in Indiana. At 1000 kWh, the Bill Survey indicates a bill of $128.90 for a Vectren South residential customer (without taxes). This billing result equals an average per kWh charge of 12.89 cents. Of the twenty-four (24) jurisdictional utilities only three (3) have average rates above 11 cents at 1000 kWh. The Bill Survey indicates that the vast majority had average rates below 10 cents per kWh.

Petitioner's Exhibit JLU-S7 provides helpful "typical bill comparisons" for the various rate classes. Page 1 of JLU-S7 shows a current bill of $142.61 for a standard residential customer using 1000 kWh. Petitioner's proposed Step One rate increase would raise that same bill to $159.14, or to nearly 16 cents per kWh.

At the hearing Petitioner's witness Mr. Carl Chapman agreed that Vectren South's rates for industrial customers are also "on the very high side in the State…."

> Q. Do you know if SIGECO's industrial rates are the highest in the State of Indiana?
>
> A. Depending on the particular industrial customer, meaning there could be differences in demand charges or something else, obviously. Again, they're going to be on the very high side in the State for the exact same reason on the pollution control stage. (Tr. B-42)[1]

Q: Please describe the concern about high costs of power production.

A: The evidence I have reviewed creates serious doubt about how competitive Vectren South is in the power production segment of its business. For example, Petitioner's witness Mr. Ronald Jochum describes the loss of firm municipal load due to municipalities' increasing access to the wholesale market, including

[1] See the transcript at pages B-40 to B-49 for discussion of Vectren South's high rates.

competitive service offers from the Indiana Municipal Power Authority.[2] Mr. Jochum describes Vectren South's limited prospects in the wholesale power market. He states that Vectren South – Electric projects wholesale power margin (WPM) results of $5.98 million for the pro forma period, compared to actual WPM of $16 million for the test year. (RGJ-1, pages 8 -9).

OUCC witness Dr. David Dismukes has performed a benchmarking analysis that compares Vectren South's power production performance to peer group companies. This empirical evidence confirms Vectren South's competitive problems as a power producer.

Q: What is Vectren South's response to these challenges?

A: Judging by its filing in this case, Vectren South's response is to increase rates to its captive retail customers and increase the certainty of its cash flows from these customers through a vast expansion of rate adjustment mechanisms (i.e. trackers). Vectren South proposes to track all non-fuel Variable Production Costs (VPCs). Fuel costs are already tracked. Vectren South also proposes to track the recovery of its fixed costs through a proposed Sales Reconciliation Adjustment (SRA) decoupling mechanism. This mechanism goes well beyond gas *distribution* rate decoupling and encompasses electric production and transmission fixed costs. For small customers, virtually every cost would be subject to a cost tracker (e.g. FAC, MCRA, RCRA, etc.) or it would be classified as a "fixed cost" subject to the SRA decoupling mechanism.

Q: Are there concerns about the test year chosen by Vectren South to conduct

[2] Petitioner's Exh. RGJ-1, p 5.

its revenue requirements study?

A: Yes. Vectren South filed its petition and case-in-chief at the same time based on a test year ended June 30, 2009. This test year represents one of the most recessionary periods since the 1930s. The data below from the U.S. Bureau of Economic Analysis show that U.S. real GDP growth was negative in each quarter of the test year.

Gross Domestic Product
Percent change from preceding period

Quarterly
(Seasonally adjusted annual rates)

	GDP percent change based on current dollars	GDP percent change based on chained 2005 dollars
2006q1	8.6	5.4
2006q2	5.1	1.4
2006q3	3.2	0.1
2006q4	4.8	3.0
2007q1	5.5	1.2
2007q2	6.0	3.2
2007q3	5.3	3.6
2007q4	4.5	2.1
2008q1	1.0	-0.7
2008q2	3.5	1.5
2008q3	1.4	-2.7
2008q4	-5.4	-5.4
2009q1	-4.6	-6.4
2009q2	-0.8	-0.7
2009q3	2.6	2.2
2009q4	6.1	5.6
2010q1	4.1	3.0

Source: U.S. Bureau of Economic Analysis.

The table above extends back to the first quarter of 2006 and shows how anomalous the test year is with four consecutive quarters of negative real GDP growth, including growth of a negative 5.4% (08 Q4) and a negative 6.4% (09 Q1). Despite having the highest electric rates in Indiana, Vectren South is the first of Indiana's large electric IOUs to seek general rate relief due in substantial measure to the recession and the associated reduction in industrial sales. The test year in this Cause is far from normal, and the Commission should use great caution when evaluating or making rates based on such a test year.

Q: Would you please introduce the OUCC's expert witnesses?

A: Yes. The following experts will testify for the OUCC.

- Dr. David E. Dismukes, Consulting Economist of Acadian Consulting Group, will address policy issues that flow from Petitioner's proposal to "decouple" its sales volumes from its fixed cost recovery in the distribution, transmission, and production segments of its business. Dr. Dismukes will provide an overview of decoupling activity around the nation, including concerns that have arisen in recent evaluations of decoupling as a tool to stimulate energy efficiency investment. Dr. Dismukes will contrast rate decoupling for a gas distribution utility with decoupling for a vertically integrated electric utility like Vectren South. Dr. Dismukes also sponsors a review of Vectren South's performance benchmarked against peer companies. This evidence reveals that Petitioner is a high cost producer of electricity relative to its peers. As an alternative to Petitioner's decoupling proposal, Dr. Dismukes proposes an Efficiency Incentive Mechanism (EIM) to promote effective provision of DSM programs and improved efficiency and competitiveness in power production. In addition, Dr. Dismukes will discuss problems with rate trackers in general, including the tendency of tracker mechanisms to weaken incentives to operate efficiently. He will also provide specific recommendations concerning the MISO Cost and Revenue Adjustment (MCRA) tracker and the addition of the Variable Production Costs (VPC) component to the existing Reliability Cost and Revenue Adjustment (RCRA) mechanism.

- Ms April Paronish of the OUCC will review Petitioner's electric DSM programs and briefly explain how the programs fit into the context of the Commission's recent generic DSM Order and its Order in Cause No. 43427. She also presents preliminary findings with regard to savings and lost margins attributable to the gas DSM programs sponsored by Vectren Corp's two Indiana gas distribution utilities (Vectren North and Vectren South – Gas). This comparison indicates that the savings and lost margins attributable to the Gas DSM Programs are relatively small when compared to the incremental revenue provided by the gas decoupling mechanisms.

- Mr. Thomas Catlin of Exeter Associates will sponsor the OUCC's overall calculation of revenue requirements. Mr. Catlin makes certain pro forma adjustments to test year revenues, expenses and rate base. Mr. Catlin's calculation of revenue requirements also relies on inputs from other OUCC witnesses. For example, Mr. Korlon Kilpatrick will sponsor the OUCC's cost of capital estimate used to calculate the return component of revenue requirements.

- Mr. Greg Foster of the OUCC will testify about adjustments proposed by Vectren South to its labor costs. Mr. Foster will describe how Vectren South has over stated the need for upward adjustments in areas such as incentive compensation, deferred compensation expense, and pension expense.

- Mr. Eric Hand of the OUCC will evaluate Petitioner's proposed upward adjustment to test year operating expenses associated with the Emerald Ash Borer. He will explain that little, if any, penetration of the Emerald Ash Borer into Petitioner's service territory has occurred. He also demonstrates the upward bias in Petitioner's estimates of the cost of removing ash trees before they become diseased. Mr. Hand will also address concerns about Petitioner's proposed changes to its existing and approved "General Terms and Conditions" of service. Mr. Hand highlights the general lack of explanation or evidence from Petitioner for these changes and provides examples of changes that are onerous to ratepayers.

- Mr. Anthony Alvarez explains his review of two extraordinary storm events that occurred during the test year. During these events thousands of customers were out of service for extended periods. Petitioner, however, made no adjustment to restore the lost revenues caused by these extraordinary outages. Mr. Alvarez used reports from Vectren South to estimate the number of customers impacted and the duration of outages. These estimates enabled Mr. Catlin to estimate lost sales associated with the two major events and include a pro forma adjustment to test year revenue to restore some of the revenue lost due to the extraordinary outages.

- Ms. Cynthia Armstrong of the OUCC will testify about Vectren South's test year Emission Allowance (EA) expenses, which greatly exceeded such expense levels in recent years. She will sponsor a pro forma adjustment to normalize EA expense. She will also address Vectren South's history of tracking EA costs and revenues and Vectren's proposal to continue tracking in the future through the RCRA mechanism. Vectren South's proposal includes flowing through all expenses and retaining a portion of revenues from the sale of EAs. Ms.

Armstrong will propose a more balanced and symmetrical treatment of EA costs and revenues.

- Mr. Wes Blakley of the OUCC will review and make recommendations regarding Vectren South's request to add Variable Production Costs (VPCs) to its existing Reliability Cost and Revenue Adjustment (RCRA) tracker. Mr. Blakley incorporates the recommendations of Dr. Dismukes (wholesale power margins) into the OUCC's overall proposal for an improved RCRA.

- Mr. Michael Eckert of the OUCC will testify regarding the level of coal inventory investment that Petitioner proposes to include in rate base. Petitioner's proposed coal inventory value is roughly double the level included in rate base in Petitioner's last rate case (Cause No. 43111). Mr. Eckert will propose a normalization adjustment to coal inventory based on a 13-month average of actual inventory levels ending with the last month of the test year. Mr. Eckert will also testify about other fuel related issues and the Fuel Adjustment Clause. Mr. Eckert also addresses Petitioner's MISO Cost and Revenue Adjustment (MCRA) tracker. Mr. Eckert explains the OUCC objections to Petitioner's unbalanced proposal to fix (i.e. not track) the level of transmission revenue while continuing to track MISO costs going forward.

- Mr. Korlon Kilpatrick of the OUCC will address Petitioner's cost of equity capital. Mr. Kilpatrick recommends a 9.25% cost of equity. When used in conjunction with Petitioner's proposed test year end capital structure, this results in an overall weighted average cost of capital (WACC) of 6.79%.

- Dr. Emma Nicholson of Exeter Associates will testify about the cost of service model runs made in support of Dr. Dale Swan's cost of service and rate design recommendations. Dr. Nicholson will also analyze Vectren South's application of the Zero Intercept model, which was used to classify line transformers (Account 368) as partly demand-related and partly customer-related. Dr. Nicholson thoroughly evaluates the data and econometric analysis performed by Petitioner in its application of the Zero Intercept model.

- Dr. Dale Swan of Exeter Associates will testify regarding Vectren South – Electric's cost of service, rate, and tariff design. Dr. Swan will comprehensively address the allocation of revenue requirements to the various rate classes. He will also explain how any revenue increase should be spread across the various rate classes. Dr. Swan will also describe how the recessionary test year in this case results in greater cost allocations to residential and small commercial customers.

III. <u>Vectren South's Proposed Step Two Rate Increase</u>

Q: Does Vectren South propose a second base rate increase in this Cause?

A: Yes. Vectren South seeks Commission approval to implement a second step (Step Two) base rate increase to cover revenue requirements associated with its dense pack project at its A.B. Brown power plant ("A.B. Brown Project" or "the Project"). The Project involves installation of dense pack technology at A.B. Brown Units 1 & 2. Vectren South plans to complete the Unit 1 installation in 2012, with Unit 2 following in 2013. Thus, the entire Project is expected to be complete and in-service in 2013.[3] Vectren South witness Ms. Susan Hardwick presents an updated estimate of the Project's revenue requirement of $4.4 million. (Pet. Exh. MSH-S6) Vectren South also seeks post-in-service allowance for funds used during construction (AFUDC) and deferred depreciation as described in Ms. Hardwick's direct testimony. This would begin after the installation at Unit 1 is complete in 2012, prior to the implementation of the Step Two rate increase in 2013.

Vectren South witness Mr. Jochum describes the dense pack technology and the expected efficiency gains associated with the Project. Vectren South witness Mr. Jerry Ulrey explains the Step Two rate design process and sponsors typical bill comparisons to show the impact on bills caused by the Step Two rate increase in 2013. Vectren South witness Mr. Scott Albertson sponsors Step Two tariff sheets (rate schedules) in Pet. Exh. SEA-4.

Q: Has Vectren South sought Commission approval of special ratemaking treatment for a dense pack project in a prior case?

A: Yes. In Cause No. 43568 Vectren South sought rate tracker treatment for its dense pack project at its Warrick Unit 4. The Commission denied the request and found

[3] Petitioner's Exh. MSH-S1, p. 10.

that the dense pack project was, in essence, a complete turbine rebuild.[4] I interpret the Commission's Order in Cause No. 43568 as affirming that this type of project can reasonably be addressed in the traditional, base ratemaking process.

Vectren South now seeks relief in this rate case related to the A.B. Brown Project. The specific relief sought by Vectren South is the Step Two base rate increase, which would take effect in 2013 after the Project is fully completed and in-service.

Q: What is the test year in this current rate case?

A: The twelve months ended June 30, 2009. Thus the A.B. Brown Project will not be complete and in-service until more than three (3) years after the test year used to determine Petitioner's actual and pro forma operating revenues, expenses, and income in this Cause. The pre-hearing conference order permits Petitioner to propose the Step Two rate increase, but it also makes clear the right of other parties to oppose a second rate increase.

Q: Does the OUCC support a Step Two rate increase in this Cause?

A: No. The Commission should not approve a rate increase proposed to take place in 2013. Vectren South effectively asks the Commission to pre-judge the ratemaking treatment of the Project at A.B. Brown, which will not be fully in-service until 2013. The Commission should deny this request and find that the ratemaking treatment of the A.B. Brown Project may be considered in a future Vectren South base rate case. If desired, Petitioner could seek post-in-service AFUDC and deferred depreciation at a time closer to the completion of the Project and closer to a future base rate case.

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[4] See Order dated June 17, 2009, Cause No. 43568, p. 9.

All parties' rights to scrutinize and potentially object to such future proposals should be preserved.

Q: Is it premature for the Commission to determine the need for rate relief in 2013 due to the A.B. Brown Project?

A: Yes. Again, a future Vectren South base rate case would be the appropriate time to determine the ratemaking treatment of the Project. Furthermore, given the highly recessionary nature of the test year in this Cause, a new base rate case in 2012 or 2013 to consider the Project and other changes to rate base, sales, revenues, and expenses would not be unreasonable.

It is difficult to predict the changes that will occur between now and 2013. Hopefully, the economy will continue to rebound from the extremely recessionary conditions embedded in Petitioner's chosen test year in this case. Recoveries in industrial production and wholesale power markets could significantly change Petitioner's financial condition and need for rate relief in 2013.

Petitioner's request for a Step Two rate increase is inherently "piece-meal." It focuses on one element of future revenue requirements, while ignoring potential changes in other factors that will impact revenue requirements, including potential economic recovery, and improved wholesale and retail sales. Indeed, Vectren South's requested Step Two rate increase would result in the recessionary test year in this Cause being used to set base rates not just once, but also a second time in 2013.

Q: Please summarize your conclusions regarding the ratemaking treatment of the A.B. Brown Project.

A: This Project will not be complete until 2013. Vetcren South's request for a Step Two rate increase in 2013 is another form of special ratemaking treatment, albeit not a tracker, for a dense pack project. The proposal is also inherently "piece-meal" because it ignores changes to other factors impacting revenue requirements between now and 2013. If approved, the proposal would also result in the recessionary test year in this Cause being used to establish new rates more than three years after the end of the test year. I recommend the Commission deny Vectren South's Step Two rate increase proposal in this Cause and find that the ratemaking treatment of the Project at A.B. Brown should be considered in a future base rate case.

IV. Proposed Weather Normalization of Earnings for the FAC Earnings Test

Q: Does Vectren South propose weather normalizing its earnings for purposes of the FAC earnings test?

A: Yes. Ms. Hardwick explains that Vectren South proposes to adjust each quarterly FAC earnings test filing for a weather normalization adjustment consistent with the weather normalization calculation performed in this rate case.[5]

My testimony here only addresses Vectren South's proposal to change the FAC earnings test by weather normalizing earnings for purposes of the statutory earnings test. OUCC witness Thomas Catlin will address Vectren South's pro forma adjustment to test year revenue for normal weather, done for ratemaking purposes in this Cause.

Q: How long has an "earnings test" existed for gas and electric utilities in the GCA and FAC, respectively?

[5] Pet. Exh. MSH-1, p. 8, line 20.

A: Some form of the earnings test has existed since the 1980s. The earnings test has received at least one major modification by the legislature when it created the 5-year earnings bank. The Commission provided a brief history of the earnings test in its November 20, 2008, Order in Cause No. 38708 FAC 78 S1. In that Order, the Commission rejected the same proposal that Vectren South now makes in this Cause to modify the FAC earnings test by weather normalizing earnings.

Q: Do any electric utilities weather normalize earnings for purposes of the FAC earnings test?

A: No. In the long history of the FAC earnings test, I am not aware of any electric utility weather normalizing earnings in the FAC earnings test. When asked in discovery, Vectren South could provide no such examples.[6]

Q: In its case-in-chief, does Vectren South identify any ratepayer benefits that would result from weather normalizing earnings in the FAC earnings test?

A: No. Vectren South's argument is that consistency requires weather normalization in the FAC earnings test, if test year revenues are weather normalized in the base rate case. The Commission did not accept this reasoning in Cause No. 38708 FAC 78 S1.

Q: What is wrong with Vectren South's argument in favor of changing the FAC earnings test?

A: In base rate cases, numerous "normalization" adjustments are made to actual test year revenue and expenses. For example, if the test year summer was unusually hot, the electric utility may propose a normalization adjustment to reduce pro forma revenue to reflect more normal conditions (and less air conditioning load). If a major industrial plant was idle during the test year due to a labor strike, a

[6] Response to OUCC DR23, Q-2.

normalization adjustment could be proposed to increase pro forma revenue to reflect a more normal level of industrial production. A major energy utility rate case can have dozens of normalization adjustments to estimate a normal (pro forma) going level of operating revenues, expenses, and income. Making such normalization adjustments in a rate case does not necessitate similar normalization adjustments for the FAC earnings test where actual earnings are compared to authorized earnings.

The purpose of a rate case is to evaluate the reasonableness of existing rates and to establish new "just and reasonable" rates, if the Commission determines a rate change is warranted. Normalization adjustments are made to determine pro forma revenues, expenses, and income and to determine the appropriate increase (or decrease) in revenues and rates.

The purpose of the earnings test is to compare actual earnings to authorized earnings. A comparison of actual to authorized earnings does not require the same types of normalization adjustments made in a base rate case. Furthermore, the summary, expedited nature of FAC proceedings does not lend itself to the types of normalization adjustments made in rate cases. Finally, Petitioner puts forth no evidence in its case-in-chief that its proposal will improve the administration of the FAC or the statutory earnings test.

Q: Has anything changed since the Commission rejected Vetcren South's proposal to weather normalize earnings in the FAC earnings test in its Order in Cause No. 38708 FAC 78 S1?

A: No. I recommend the Commission reaffirm its findings in that Cause, which included:

> There is no dispute that without weather normalizing actual earnings Vectren South has exceeded the statutory earnings test in at least FAC 78. Neither the Commission's Order in Cause No. 37712 nor the statute, Ind. Code § 8-1-2-42(d)(3), contemplate weather normalizing returns in the FAC earnings test. Vectren South's requested relief is for an equitable remedy based on a Commission Order in a general investigation applicable to utilities in the gas industry, which has inherent differences from the electric industry. The differences, as discussed herein, do not lend themselves to approving such requested relief. Order, p. 7.

For the second time Vetcren South seeks a modification to the FAC earnings test to weather normalize earnings. Vectren South presents no new evidence or arguments in favor of its proposed changes. The Commission should again deny the proposal.

Q: Does Vetcren South propose other changes to the FAC, in addition to the change to the earnings test?

A: Yes. OUCC witness Mr. Michael Eckert addresses those changes in detail. I will restrict my comments here to Vectren South's proposal to remove all trackable fuel cost from base rates. For large electric utilities like Petitioner, the Commission has traditionally included a base amount of fuel costs in base rates. The fuel adjustment clause (FAC) is used to track changes (up or down) from the base cost of fuel.

Vectren South witness Mr. Ulrey explains the perceived advantages of tracking all fuel costs through the FAC.[7] The OUCC does not dispute the fact that all fuel costs could be recovered through a tracker with none recovered through base rates. The OUCC also understands that some gas utilities have

[7] Petitioner's Exh. JLU-1 (revised) pp. 19-21.

adopted the practice of recovering all "gas costs" through the GCA with no gas costs included in base rates.

Q: Are there differences between gas distribution utilities and vertically integrated electric utilities that the Commission should consider when evaluating Vectren South's proposal to remove all fuel costs from base electric rates?

A: Yes. A primary difference to consider is that Vectren South – Electric is a producer of electricity. Fuel is a major input into Vectren South's production of electricity, in addition to capital and labor and other materials. Fuel for power production is a major component of the total retail electric revenue requirement for all retail customers. Indiana electric customers have no choice of supplier, whereas many large volume gas customers can elect to purchase gas from a third party marketer and have their gas delivered by the local gas distribution company (LDC). Gas utilities deliver fuel to retail customers. Vertically integrated electric utilities burn fuel to produce electricity.

Given the complex and dynamic nature of the power industry, the OUCC continues to see value in the traditional process of comprehensively quantifying the jurisdictional revenue requirement, comprehensively allocating the revenue requirement to the rate classes, and designing base rates to recover the revenue requirement. At this time, the OUCC does not support omitting major revenue requirements, like fuel costs, from base rates. The OUCC continues to advocate the need for base rates designed to comprehensively recover the jurisdictional revenue requirement as determined at the time of the base rate case.

Q: Does this conclude your direct testimony?

A: Yes.

2009 Residential Bill Survey
Jurisdictional Electric Utilities
July 1, 2009 Billing

Commission Staff presents a survey of electric utility billings for residential customers served under Indiana state rate-setting jurisdiction. The surveyed providers to these customers include 5 investor-owned, 4 co-operative and 15 municipal Utilities. We note that 61 municipal and 38 co-operative electricity providers within the state are excluded as non-jurisdictional.

We present the results in a variety of ways to improve the transparency of data collected. All rates included in this survey are those applicable on customer bills issued July 1. The initial tables show the July 1, 2009 bill applicable to simple tariff residential customers at 500, 1000, 1500, and 2000 kWh monthly consumption levels first alphabetically and then ranked by 1000 kWh cost, highest being 1st. Next we present the year over year change to the customer bills at 1000 kWh. The survey includes all rate trackers but excludes taxes. Expense and capital trackers provide a means to include cost changes in customer rates outside of a traditional rate case. The fuel and power cost tracker for each municipal in 2009 is compared to 2008 in Table 4. The investor-owned group employs a variety of tracking mechanisms for which the 2009 and 2008 charges are listed for comparison. Table 6 has been added to disaggregate the base and variable cost components of 1000 kWh consumption. Figure Nos. 1 and 2 show the investor-owned electric utilities 1000 kWh residential customer bills for the current and historical periods, respectively.

Table/Figure List

Table 1

JURISDICTIONAL ELECTRIC UTILITY RESIDENTIAL CUSTOMER BILL SURVEY
[July 1, 2009 Billing] By Utility Name and Type

	kWh Consumption				
MUNICIPAL UTILITIES	**500**	**1000**	**1500**	**2000**	**Overall Ranking***
Anderson Municipal	$ 53.77	$ 97.69	$ 141.62	$ 183.34	10
Auburn Municipal	29.16	53.32	77.48	101.64	24
Columbia City Municipal	47.10	86.70	126.31	165.91	16
Crawfordsville Municipal	47.51	88.04	126.36	164.68	15
Frankfort Municipal	46.42	82.57	118.72	150.57	21
Kingsford Heights Municipal	50.19	96.87	143.56	190.25	11
Knightstown Municipal	49.12	93.63	133.84	174.05	14
Lebanon Municipal	46.24	85.72	121.39	157.06	17
Logansport Municipal	53.42	98.02	140.21	181.40	9
Mishawaka Municipal	45.30	80.61	115.92	151.23	22
Peru Municipal	51.24	95.91	138.97	182.03	12
Richmond Municipal	55.24	94.93	134.63	172.59	13
Straughn Municipal	38.92	76.04	113.17	150.29	23
Tipton Municipal	44.52	83.04	119.27	155.50	20
Troy Municipal	60.59	115.45	170.32	225.18	3
COOPERATIVE UTILITIES					
Harrison County REMC	$ 62.77	$ 106.56	$ 146.35	$ 181.58	6
Jackson County REMC	60.54	106.08	151.61	197.15	7
Marshall County REMC	73.11	128.68	173.74	218.81	2
Northeastern REMC	63.65	108.86	154.06	193.76	4
INVESTOR OWNED UTILITIES					
Duke Energy Indiana	$ 59.90	$ 98.75	$ 132.77	$ 166.77	8
Indiana Michigan Power D/B/A AEP	45.72	84.64	123.56	162.48	18
Indianapolis Power & Light Co.	52.97	83.43	113.91	144.38	19
Northern Indiana Public Service Co.	57.61	108.56	159.51	210.46	5
So. Indiana Gas & Electric Co. D/B/A Vectren	69.23	128.90	188.58	248.25	1

*Overall Ranking based on Total Rate at 1000 kWh consumption.

Table 2

JURISDICTIONAL ELECTRIC UTILITY RESIDENTIAL CUSTOMER BILLS
[July 1, 2009 Billing]
Overall Ranking for 1,000 kWh of Consumption

		<---------kWh Consumption--------->			
	NAME	500 kWh	1000 kWh	1500 kWh	2000 kWh
1	So. Indiana Gas & Electric Co. D/B/A Vectren	$ 69.23	$ 128.90	$ 188.58	$ 248.25
2	Marshall County REMC	$ 73.11	$ 128.68	$ 173.74	$ 218.81
3	Troy Municipal	$ 60.59	$ 115.45	$ 170.32	$ 225.18
4	Northeastern REMC	$ 63.65	$ 108.86	$ 154.06	$ 193.76
5	Northern Indiana Public Service Co.	$ 57.61	$ 108.56	$ 159.51	$ 210.46
6	Harrison County REMC	$ 62.77	$ 106.56	$ 146.35	$ 181.58
7	Jackson County REMC	$ 60.54	$ 106.08	$ 151.61	$ 197.15
8	Duke Energy Indiana	$ 59.90	$ 98.75	$ 132.77	$ 166.77
9	Logansport Municipal	$ 53.42	$ 98.02	$ 140.21	$ 181.40
10	Anderson Municipal	$ 53.77	$ 97.69	$ 141.62	$ 183.34
11	Kingsford Heights Municipal	$ 50.19	$ 96.87	$ 143.56	$ 190.25
12	Peru Municipal	$ 51.24	$ 95.91	$ 138.97	$ 182.03
13	Richmond Municipal	$ 55.24	$ 94.93	$ 134.63	$ 172.59
14	Knightstown Municipal	$ 49.12	$ 93.63	$ 133.84	$ 174.05
15	Crawfordsville Municipal	$ 47.51	$ 88.04	$ 126.36	$ 164.68
16	Columbia City Municipal	$ 47.10	$ 86.70	$ 126.31	$ 165.91
17	Lebanon Municipal	$ 46.24	$ 85.72	$ 121.39	$ 157.06
18	Indiana Michigan Power D/B/A AEP	$ 45.72	$ 84.64	$ 123.56	$ 162.48
19	Indianapolis Power & Light Co.	$ 52.97	$ 83.43	$ 113.91	$ 144.38
20	Tipton Municipal	$ 44.52	$ 83.04	$ 119.27	$ 155.50
21	Frankfort Municipal	$ 46.42	$ 82.57	$ 118.72	$ 150.57
22	Mishawaka Municipal	$ 45.30	$ 80.61	$ 115.92	$ 151.23
23	Straughn Municipal	$ 38.92	$ 76.04	$ 113.17	$ 150.29
24	Auburn Municipal	$ 29.16	$ 53.32	$ 77.48	$ 101.64
	Average	$ 52.68	$95.13	$136.08	$176.22
	2008 Survey	$ 48.33	$86.28	$122.72	$158.37
	% Change	8.99%	10.26%	10.88%	11.27%

Table 3

Jurisdictional Electric Utility Residential Customer Bill
1000 kWh Usage, July 1 Billing (By Name)
Year to Year Comparison

MUNICIPAL UTILITIES	2009	2008	% Change
Anderson Municipal	$ 97.69	$ 84.41	15.73%
Auburn Municipal	$ 53.32	$ 48.50	9.93%
Columbia City Municipal	$ 86.70	$ 84.25	2.91%
Crawfordsville Municipal	$ 88.04	$ 81.85	7.57%
Frankfort Municipal	$ 82.57	$ 76.60	7.80%
Kingsford Heights Municipal	$ 96.87	$ 80.08	20.97%
Knightstown Municipal	$ 93.63	$ 82.12	14.01%
Lebanon Municipal	$ 85.72	$ 79.39	7.97%
Logansport Municipal	$ 98.02	$ 91.34	7.32%
Mishawaka Municipal	$ 80.61	$ 63.53	26.90%
Peru Municipal	$ 95.91	$ 82.08	16.85%
Richmond Municipal	$ 94.93	$ 81.33	16.72%
Straughn Municipal	$ 76.04	$ 77.17	-1.46%
Tipton Municipal	$ 83.04	$ 81.32	2.12%
Troy Municipal	$ 115.45	$ 103.84	11.18%
Muni Averages	**88.57**	**79.85**	**10.91%**
COOPERATIVE UTILITIES			
Harrison County REMC	$ 106.56	$ 97.85	8.90%
Jackson County REMC	$ 106.08	$ 87.57	21.13%
Marshall County REMC	$ 128.68	$ 118.63	8.47%
Northeastern REMC	$ 108.86	$ 99.34	9.58%
Co-op Averages	**112.54**	**100.85**	**11.60%**
INVESTOR OWNED UTILITIES			
Duke Energy Indiana	$ 98.75	$ 96.62	2.20%
Indiana Michigan Power D/B/A AEP	$ 84.64	$ 73.66	14.90%
Indianapolis Power & Light Co.	$ 83.43	$ 74.72	11.66%
Northern Indiana Public Service Co.	$ 108.56	$ 105.37	3.03%
So. Indiana Gas & Electric Co. D/B/A Vectren	$ 128.90	$ 119.04	8.29%
IOU Averages	**100.86**	**93.88**	**7.43%**

Table 4

Jurisdictional Municipal Electric Utility Residential Customer Bill
1000 kWh Usage, July 1 Billing (By Name)
Year to Year Comparison
Fuel/Power Factor Adjustment Mechanism

Fuel/Power Factor Charge @ 1000 kWh	2009	2008	Change
Anderson Municipal	$29.42	$21.66	$7.76
Auburn Municipal	9.73	4.92	4.82
Columbia City Municipal	25.99	23.54	2.45
Crawfordsville Municipal	23.34	17.14	6.19
Frankfort Municipal	26.21	20.24	5.97
Kingsford Heights Municipal	29.47	12.68	16.79
Knightstown Municipal	28.62	17.12	11.50
Lebanon Municipal	21.25	14.92	6.33
Logansport Municipal	24.03	22.70	1.33
Mishawaka Municipal	21.26	4.18	17.09
Peru Municipal	21.40	7.57	13.83
Richmond Municipal	30.30	16.70	13.60
Straughn Municipal	10.86	11.98	(1.13)
Tipton Municipal	17.40	15.68	1.72
Troy Municipal	56.83	45.22	11.61

Table 5

Indiana Investor-Owned Electric Utilities
Year to Year Comparison
Adjustable Rate Mechanisms on Residential Bills
1000 kWh Usage, July 1 Billing

	2009	2008	Change
	$	$	$
Indiana Michigan Power D/B/A AEP			
FAC	8.72	6.10	2.62
DSM	0.00	0.00	0.00
Off-System Sales Sharing	(1.77)	0.00	(1.77)
RTO	2.78	0.00	2.78
QPCP & QPCP O&M	0.00	0.00	0.00
EA	0.60	0.00	0.60
Merger Savings (Settlement)	0.00	(0.93)	0.93
Total	10.34	5.17	5.17
Indianapolis Power & Light Co.			
FAC	8.91	7.81	1.10
Voluntary Credit applied via FAC	0.00	(7.30)	7.30
QPCP & QPCP O&M	7.00	6.96	0.04
DSM	0.73	0.56	0.17
ACLM	0.30	0.20	0.11
Total	16.93	8.22	8.71
Northern Indiana Public Service Co.			
FAC	7.16	4.69	2.47
QPCP	3.03	2.28	0.75
QPCP O&M	1.31	1.02	0.29
Customer Credit (Settlement)	(6.36)	(6.04)	(0.32)
Total	5.14	1.95	3.19
Duke Energy Indiana			
FAC	12.90	13.52	(0.62)
QPCP	4.36	3.03	1.33
QPCP O&M	4.04	2.62	1.42
EA	(0.17)	0.39	(0.56)
DSM	0.55	0.87	(0.32)
MISO	0.75	1.43	(0.68)
IGCC	1.49	0.00	1.49
Summer Relability	0.22	0.12	0.10
Amortization Phase Out	(0.59)	(0.56)	(0.03)
Total	23.55	21.42	2.13
So. Indiana Gas & Electric Co. D/B/A Vectren			
FAC	9.93	(1.37)	11.30
QPCP	3.47	1.33	2.14
QPCP O&M	3.12	0.00	3.12
MISO	(3.35)	1.58	(4.93)
Reliability (RCRA)	(3.27)	(1.41)	(1.85)
DSM	0.09	0.00	0.09
Total	10.00	0.13	9.78

FAC = Fuel Adjustment Charge
QPCP = Qualified Pollution Control Property
DSM = Demand Side Management
ACLM = Air Conditioning Load Management
QPCP O&M = Qualified Polltion Control Property Operation & Maintenance
EA = Emission Allowance
IGCC = Clean Coal Tracker for Gasification Plant
RTO = Midwest ISO or PJM ISO Non-fuel

Table 6

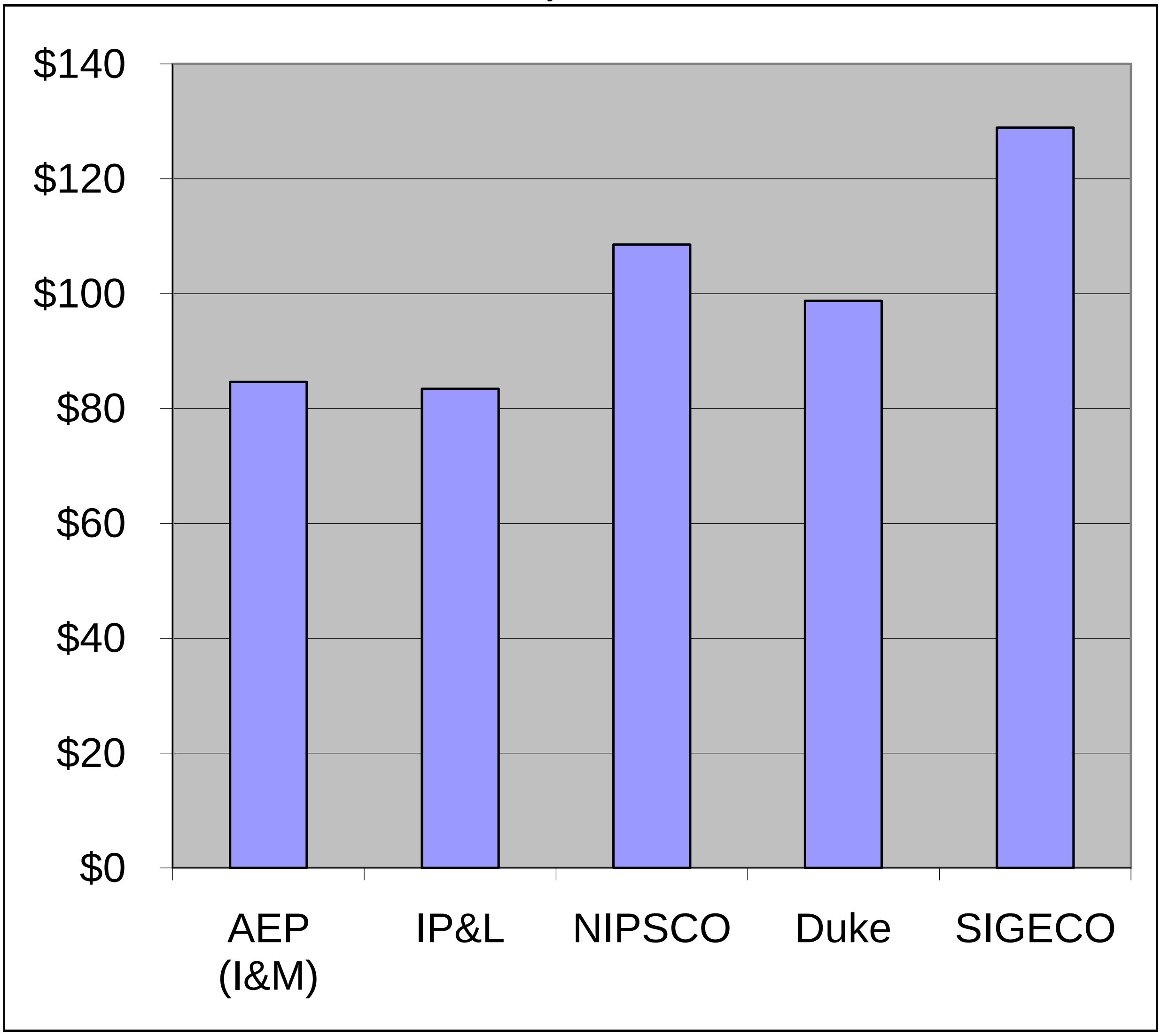
Indiana Investor-Owned Electric Utilities
Base and Variable (Tracker) Bill Components
1000 kWh Usage, July 1, 2009 Billing

	Base	Variable	Total
	$	$	$
Indiana Michigan Power D/B/A AEP	74.30	10.34	84.64
Indianapolis Power & Light Co.	66.50	16.93	83.43
Northern Indiana Public Service Co.	97.06	11.50	108.56
Duke Energy Indiana	74.61	24.14	98.75
So. Indiana Gas & Electric Co. D/B/A Vectren	118.90	10.00	128.90

Notes:
Northern Indiana Public Service Co. Base amount includes a $6.36 credit applied through the FAC
Duke Energy Indiana Base amount includes a $0.59 amortization removal credit

Figure 1

Comparison of Investor Owned Utilities
Residential Electric Bills at 1,000 kWh
July 1, 2009

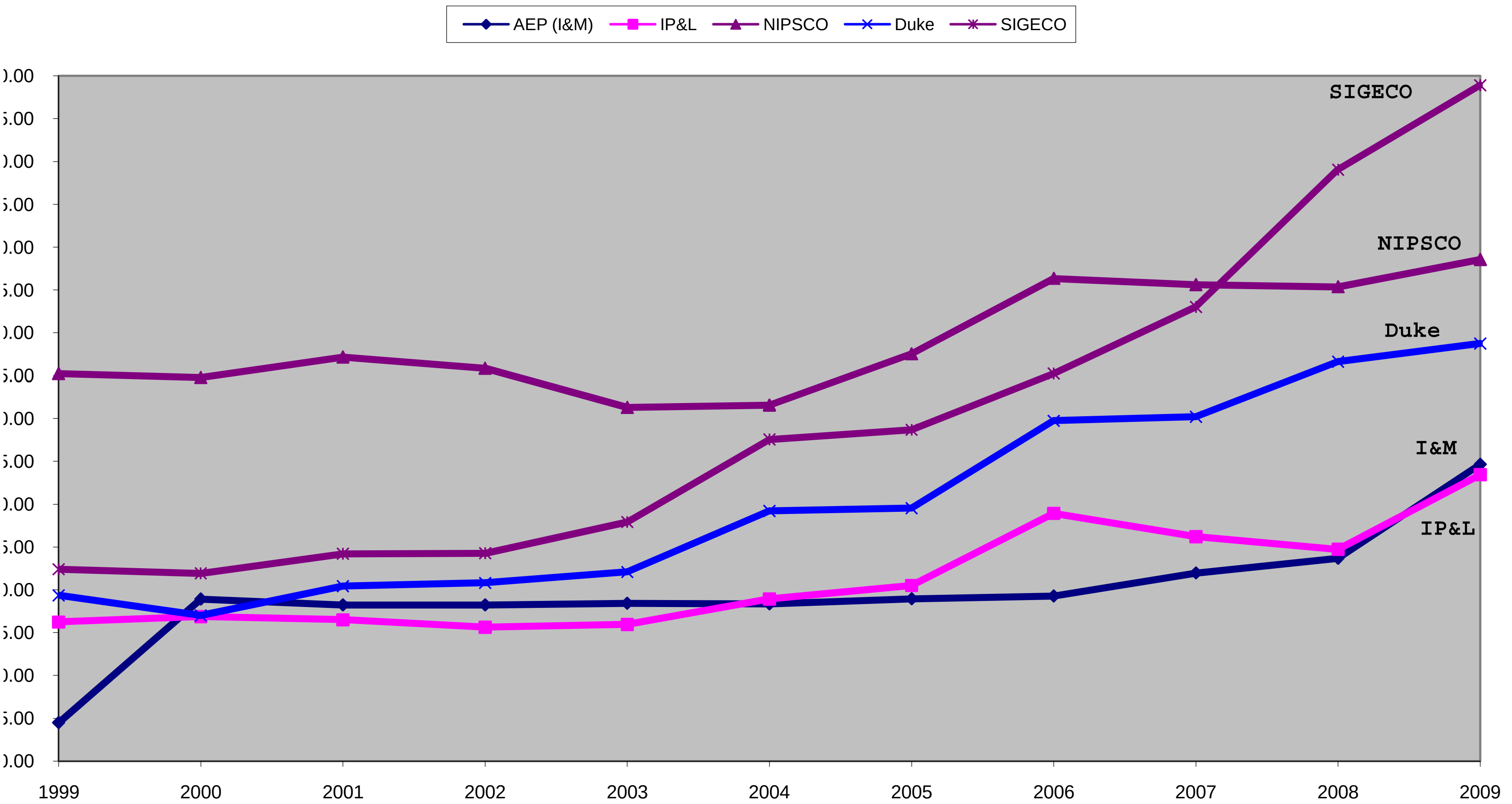


	1,000 kWh	Overall Ranking*
Indiana Michigan Power D/B/A AEP	$ 84.64	18
Indianapolis Power & Light Co.	$ 83.43	19
Northern Indiana Public Service Co.	$ 108.56	5
Duke Energy Indiana	$ 98.75	8
So. Indiana Gas & Electric Co. D/B/A Vectren	$ 128.90	1

*Overall Ranking based on evaluation of 24 utilities.

Figure 2

10 Year Comparison of Investor Owned Utility Residential Electric Bills at 1,000 kWh



Utility		Change			
		5 Years		10 Years	
American Electric Power Co. (I&M)	AEP (I&M)	$16.30	23.9%	$30.16	55.4%
Indianapolis Power & Light	IP&L	$14.51	21.1%	$17.21	26.0%
Northern Indiana Public Service Co.	NIPSCO	$17.01	18.6%	$13.34	14.0%
Duke Energy Indiana	Duke	$19.55	24.7%	$29.39	42.4%
Southern Indiana Gas & Electric Co.	SIGECO	$41.36	47.2%	$56.51	78.1%

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Tyler Bolinger

By: Tyler E. Bolinger
Indiana Office of
Utility Consumer Counselor

June 25, 2010
Date

Cause No. 43839